8.0 Electricity Service Reliability

ESSB 6560 directs the agencies to examine:

The current level of service quality and reliability as measured by available statistics, trends affecting quality of service and the integrity and reliability of the distribution system, and ways to ensure high service quality and reliability in the future;

Previous sections of this report document that electricity generation costs and retail rates are low in Washington compared to those in the rest of the country. That fact is important, but electricity service is diminished in value if it is not reliable. We depend on electricity as a critical component of our lives at home and at work. In fact, we depend on it so much that we take it for granted, until something goes wrong.

8.1 Introduction

The reliability of electric service can be described through answers to three questions.

- ❖ Is the power there when I need it?
- ❖ Is it the right voltage and frequency?
- ❖ Can I consume as much as I need (or my contract allows)?

If the answer is “no” to any of these questions, our ability to rely on the electricity system is undermined. The more frequently the answer is “no,” the more unreliable is the service. These three questions address the three fundamental dimensions of reliability: delivery interruptions, power quality and system adequacy. These dimensions can be measured by physical performance data.

A fourth and equally important dimension of reliability is consumer expectation and perception. Consumers are the beneficiaries of a reliable system and consumers are the ones who are asked to pay for it. Ultimately, understanding reliability requires understanding both the engineering performance measures and the level of consumer satisfaction with system performance. The “right” level of reliability is not determined by the engineering data alone or by consumer expectation alone. It is the combination of engineering performance that satisfies consumers at a cost they are willing to pay.

In this section, we examine electricity reliability in four ways:

1. We present current levels of reliability measured from the perspective of the consumer, as well as data collection and interpretation issues.
2. We present current levels of reliability measured by engineering performance, as well as data collection and interpretation issues.
3. We describe and discuss factors and issues that are likely to affect electricity service reliability.

4. We describe actions and policies for preserving high levels of service reliability.

8.2 Consumer Perspective

Since consumers are the ultimate beneficiary of electricity system reliability, customer perspective is the most definitive measurement of whether the system is meeting needs and expectations.

Twelve utilities were required to submit customer satisfaction surveys to the state under ESSHB 2831.[1] These surveys arrived in time for consideration in this study. Unfortunately, most surveys do not address reliability as a separate and specific issue. Table 8.1 describes how utilities address reliability in their surveys. Except for the utilities that specifically asked their customers to rate reliability, it is difficult to conclude from these surveys what customers think about the reliability of their service. It is reasonable to infer that if customers are satisfied with the utility as a whole then they must be satisfied with service reliability, but this is more a general conclusion than a specific one.

Table 8.1: Utility Customer Satisfaction Surveys and Reliability

Number of Utilities	Approach
3	No surveys taken
4	Asked customers to rate satisfaction with company “overall,” but no specific reference to reliability. Customers may have been asked why they provided such a rating, which may have led them to mention reliability issues.
5	Asked customers to rate some aspects of reliability, but with great variability in depth of coverage. The utility may have asked a single question such as, “was the response to outages timely,” or “should reliability be a priority for the utility?” Only three utilities asked customers to rate reliability performance specifically. Only one asked customers to rate a number of reliability aspects including power quality.

General customer satisfaction statistics can be difficult to interpret, let alone compare. One utility asked five different questions and reported a single, mixed approval rating. For most utilities a satisfied customer is defined as one answering in the top categories of a range, such as answering “excellent” and “good” in a range that also includes “fair” and “poor,” or answering 6 or 7 in a range of 1 to 7. Results were often reported as a percentage, for example, “85 percent of customers are satisfied.”

Based on statistics calculated in this way, utilities reported the range of satisfied customers to be from 70 to mid 90 percent. Responses to questions specifically focused on reliability showed satisfaction to be in the 70 to high 80 percent range.

These data do not provide a very definitive look at what is arguably the most important measurement of the reliability of Washington's electricity system. However, such surveys are the only information currently available. While these results suggest that consumers may be generally satisfied, the importance of the issue and the changing environment faced by utilities both argue for more definitive and regular measurement of the consumer's view of service reliability.

8.3 Engineering Performance Perspective:

While the consumer's perspective of reliability is important, the engineering perspective can provide actual yardsticks for measuring what level of performance the system is delivering. The three performance dimensions of reliability referred to above are measured in different ways. In many cases, however, it is difficult to get consistent data because utility data collection and interpretation vary. This means that the engineering performance data are useful, but must be considered very carefully. Detailed analysis of trends and comparison of performance among utilities is, in many cases, problematic. The data are primarily useful to provide a sense of the average performance of distribution systems in the state.

8.3.1 Power Delivery Interruption.

The most important aspect of reliability is power delivery; whether the power is on or off. Power delivery is measured by a number of indices that count the number of times power is interrupted and for how long. There is no federal or industry standard for these indices. A committee of the Institute of Electrical and Electronic Engineers Inc. (IEEE), has proposed a reliability standard.[2] The IEEE will likely adopt this proposed standard, or a similar one, before the end of 1998. Some states, including California and Oregon, use a similar standard to measure utility performance. Information consistent with the proposed IEEE standard was reported by the utilities as key indicators of engineering performance reliability. Specifically, two of the proposed indices were identified by the utilities as useful performance measures. The System Average Interruption Frequency Index or SAIFI, is the average number of interruptions experienced by customers during the year. A customer interruption is recorded each time an individual customer experiences a loss of service. These interruptions are summed and divided by the total number of customers to find a utility average. A SAIFI of "2" means there were two interruptions for each customer during the year. This is an average; some customers experienced more than two interruptions and some fewer.

The System Average Interruption Duration Index or SAIDI, is the average number of minutes of interruption experienced by customers during the year. A SAIDI of "10.5" means there were ten and one-half minutes of interruption for each customer during the year. This also is an average.

The SAIFI and SAIDI indices for each utility are reported in Appendix __, along with other utility system and reliability information.

Power Delivery Interruption: Data Limitations

Comprehensive collection of consistent system performance and interruption data is both difficult and expensive. Consequently, much of the data provided by the utilities for this report may suffer from both inconsistency and lack of precision. Thoroughness of data collection varies among the utilities. For example, not all utilities collect data consistent with the proposed SAIFI and SAIDI industry standards. The proposed standard only counts "sustained interruptions," which are defined as those lasting five minutes and longer. Some utilities maintain information on all interruptions, no matter how fleeting in duration.[3] Others collect data that may lead to inconsistent or misleading calculations.[4]

Increasing sophistication and capability in data monitoring also complicates interpretation of service interruption and duration figures. Utilities are constantly trying to improve their methodology to develop more accurate estimates. This makes it difficult to trace trends in reliability at a single utility, let alone across the industry. For example, in 1996 Seattle City Light changed the way it counts distribution line-miles from a manual process to one based on a Geographic Information System. Although there was no actual loss of distribution line, the utility reported a one year change from 2,568 miles to 1,836 miles; nearly a 30 percent reduction! This is a consequence of more accurate measurement, but it complicates examination of trends in factors such as maintenance expenditures per mile of distribution line. Several utilities report that their SAIFI and SAIDI numbers are deteriorating even as they believe their reliability is improving; again, a function of better counting not decreasing performance. The IEEE reports hearing estimates of up to 100% increases in SAIFI due to better measurement, record-keeping, and calculations. The agencies asked utilities about the effect of changes in data acquisition and analysis methodology on the interruption and duration data they reported. Other than to point to increasing accuracy and coverage, only one was able to quantify an effect: an increase in interruptions of from 5 to 20 percent.

Until recently, utilities nationwide have not valued detailed system-wide customer reliability data very highly. The cost of data acquisition and management did not justify the investment. Many utilities preferred to spend money on operating and maintaining the distribution system, not keeping detailed records about its performance. Knowledgeable employees "knew" which lines had problems and when equipment needed upgrading, repair or replacement. Operations personnel and planners worked together without extensive reliability data. In many cases, historical performance data is either unavailable or only crudely measured.

With the advent of computers and digital communications such information has become more cost-effective. At the same time, with the rise of competition, detailed customer information has become more valuable. Most utilities are now investing in data management systems that will make more precise reliability data more readily available. But utilities are proceeding at different paces and none in Washington has yet implemented a data management system that is entirely comprehensive and free of reliance on some level of estimation.

The lesson of the forgoing discussion is that even the most standard engineering performance measures have significant limitations. Unfortunately, these weaknesses limit their value for purposes in which we have the most interest: providing consistent measures of current levels of reliability, tracing trends over time and for comparing one utility (or group of utilities) to another. Nevertheless, these are the best reliability performance indices available. And, so long as we keep these limitations in mind, they allow for some observations about performance reliability in Washington to be made.

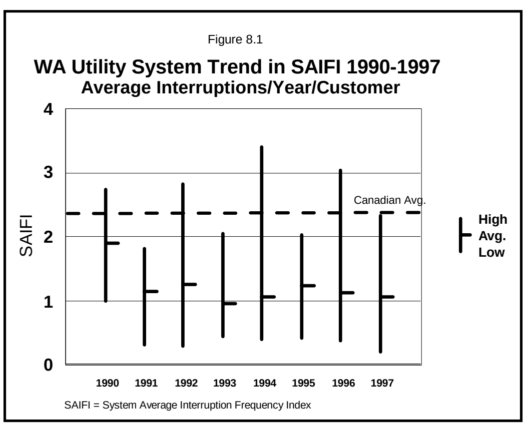
Power Delivery Interruption: Data for Washington Utilities

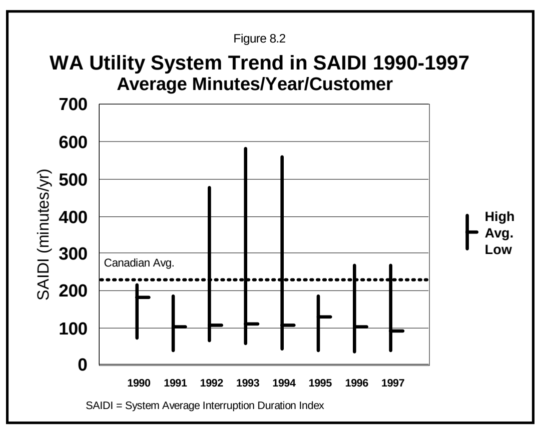
Table 8.2 includes the statewide average SAIFI and SAIDI for 1997 and compares these figures with like indices for the nation, Canada and the United Kingdom. Washington figures compare favorably. The 1997 Washington figures are close to the average for the state over the last 8 years. Over that period, the average customer in Washington has experienced about one interruption per year lasting about two hours (SAIFI = 1.19 interruptions, SAIDI = 114.47 minutes).[5]

Table 8.2: Comparison of System Average Interruption Frequency and Duration Indices.

	Washington 1997	U.S. Average 1995*	Canada 1997	United Kingdom 1997
SAIFI	1.06	1.26	2.35	8.90**
SAIDI	91.59	117.00	222.00	80.00

* Latest IEEE Industry Survey.
** UK statistics include momentary interruptions.





Figures 8.1 and 8.2 track the statewide average over 1990 through 1997 in SAIFI and SAIDI, respectively, as well as the range among the utilities included in the averages. Over this period, the lowest number of statewide interruptions occurred in 1993, when 0.96 interruptions per customer were reported. The highest number of interruptions, 1.91 per customer, occurred in 1990. Given the diversity of weather conditions

over this period, a range of 0.96 to 1.91 in the statewide average is not large. Moreover, the average consistently falls between 1 and 2 interruptions (of greater than 5 minutes) for the typical customer with no clear increasing or decreasing trend evident over the period.

The statewide average SAIDI ranged from a low of 91.6 minutes in 1997 to a high of 181.5 minutes in 1990. Again, considering variation in weather from year to year, this range in the statewide average is modest. And, there is no clear increasing or decreasing trend evident in the average SAIDI over the period.

Variation among utilities was significant, but also not excessive given the difference in utility territory characteristics and the data consistency problems noted above. The lowest SAIFI reported by any utility over the period was 0.2 in 1997; the highest was 3.4 in 1994.[6] The lowest SAIDI reported was 37.3 in 1996; the highest was 581.8 in 1994. Where individual utilities fell in these ranges varied from year to year, with no utility consistently appearing at either the high or the low end.

The SAIFI and SAIDI measure averages for the utility's distribution system, so it is important to remember that they reveal nothing about the extreme values that may be included in the average. A low SAIFI or SAIDI could result from circumstances where all customers experience a low number of interruptions, or they could reflect circumstances where most customers experience no interruptions, while others experience a great number. Portions of a utility's service territory might have very poor reliability. This is not revealed by a system-wide average SAIFI or SAIDI.

The Utility Data Survey asked utilities if they could submit data for sub-sections of their systems, such as: best and worst performing feeders, and low- and high-density feeders (as surrogates for rural and urban areas). Nine utilities reported they do collect and maintain information at the sub-system level. Some maintain data for relatively small sections of their systems, such as for communities or even small laterals. No utility can provide the data for each customer.[7] Time limitations did not permit a second round of data collection to examine sub-system variation and averages in this study. We are unable to report or compare the reliability of service for individual customers or selected sub-circuits that might represent industrial and residential customers, urban and rural customers or communities of differing demographics or other characteristics.

Power Delivery Interruption: Storms and Other Extraordinary Events

Environmental conditions are probably the greatest overall cause of interruptions. Even equipment failure, such as underground cable breakage, is often the result of deterioration brought on by contact with soil and water. Weather-related interruptions are common; most tree and branch-caused interruptions are really caused by wind, rain, ice and snow. The most serious weather-caused interruptions result from major storms.

Five utilities were able to report SAIFIs and SAIDIs for storms and other extraordinary events separately from other interruptions. By comparing these to their full interruption statistics it is possible to see the significance of these events. Storms were responsible for a significant number of the total interruptions reported by the five utilities in 1997 and an even greater percentage of minutes of interruption.

Table 8.3: Percentage of Interruptions and Minutes of Interruption Caused by Storms at Five Utilities in 1997[8]

	Seattle City Light	Cowlitz County PUD	Puget Sound Energy	Inland Power & Light	Snohomish PUD
Percent of SAIFI	13.3%	25.0%	32.0%	41.2%	51.0%
Percent of SAIDI	30.0%	31.4%	48.0%	61.7%	87.0%

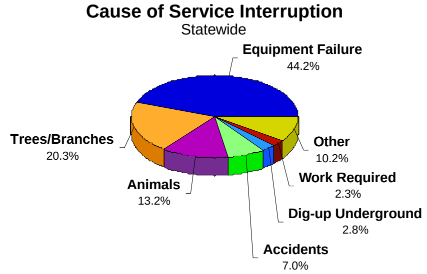
Source: Data reported by utilities to 6560.

Comparison of these statistics is difficult because of the general limitations of data described earlier and because the definition of "extraordinary event" varies from utility to utility. However, these figures do support two general observations. First, while storms account for a significant proportion of interruptions for all five of these systems, storms account for a larger percentage of total interruptions for those systems that are generally more rural in character. Much of Seattle's distribution system in the central city is underground. Second, storms contribute a greater percentage of average interruption duration (proportion of SAIDI) than interruption frequency for all five of these utilities. This is just another way of saying that storm damage takes longer to repair than other equipment failures. Steps taken to minimize storm damage and to improve response capability could have a significant impact on service reliability in Washington.

Power Delivery Interruption: Classification of Causes

Whether associated with storms or not, most utilities are able to report the principal causes of service interruptions. Not counting the amorphous "other" category, Figure 8.3 indicates that four categories account for the majority of the causes for interruptions: Equipment Failure, Trees and Branches, Animals, and Accidents. These were the cause of more than 80 percent of interruptions in Washington in 1995, 1996 and 1997.

Figure 8.3



Source: Data Reported by WA Utilities

Interruptions Caused by Equipment Failure

Failure of installed equipment is by far the largest cause of interruptions on both sides of the state. The data available for this study do not include sufficient detail to support conclusions about why equipment failed. Equipment failure reflects to some degree the relationship between operations policy and maintenance practices. We discuss system maintenance and its relationship to equipment failure in more detail in Section 8.4: Factors and Trends Affecting Electricity System Reliability.

There is a real possibility that the category “equipment failure” may be exaggerated. Some interruptions may have been categorized in this way when no other cause was identified. While such interruptions might more properly be categorized as “unknown,” not all utilities maintain such a category. In other cases, a clear cause may be evident, such as an ice storm, but the utility does not have an ice-caused category.

In addition, it may be both practical and reasonable for a utility to allow some equipment to fail and be repaired before it is replaced. Underground cable is a good example. Cable is difficult to inspect and expensive to replace. It may be sound maintenance and management policy to replace a section of cable only after a few failures indicate it is deteriorating. However, the policy does increase the number of interruptions caused by failed equipment.

Each utility tracks the causes of interruptions in its own way. Utilities may use different cause categories or have different definitions for what is included in the same category. These differences make it difficult to track the causes for interruption statewide in a fully consistent way. Worse, inconsistency in classification of causes may even make it difficult for some utilities to track trends in cause of interruption on their own systems. The industry association, IEEE, is considering the inclusion of consistent cause codes in its reliability standard.

System maintenance is a key factor affecting equipment failure. However, the need for system maintenance varies significantly across the state. An area with few trees, few customers, and a mild climate may have minimal need for maintenance. On the other hand, a system serving an area with a severe climate, many trees, and a concentrated customer base may have more need for systematic maintenance. Maintenance effort may also vary because of customer service preferences. A utility may choose to incur greater maintenance costs to provide a higher level of reliability.

In 1997, utility maintenance expenditures varied from $323 per mile of distribution line to $16,438 and from $25 per customer to $192.[9]

Interruptions Caused by Trees

Utilities on both sides of the state also report falling trees and branches as a major cause of interruptions (20% Statewide, 21% West Side, 16% East Side). As a percentage of all interruptions, tree-caused interruptions reported by individual utilities in 1997 ranged from 4.49 percent to 64.58 percent, reflecting in part the differences in forest types across the state.

The “tree-caused” category suffers from some of the same classification problems as equipment failure. Interruptions caused by an ice-laden branch may be categorized as ice-caused or tree-caused depending on the utility or the crewmember that reports it. Nevertheless, trees are a major cause of interruptions throughout the Northwest.

All utilities have vegetation management programs designed to reduce tree-caused interruptions. Programs may include trimming and removing tress, injecting growth inhibitors to slow growth, or working with property owners to help them select “line-friendly” trees (i.e. slow growing trees, or those that attain low maximum heights).

Like maintenance in general, trimming requirements and local conditions result in large differences among utility vegetation management programs and budgets. In 1997, utilities reported trimming over 15,000 miles of utility right-of-way (ROW). The range among utilities was from 300 to 1559 miles and expenditures ranged from $126 per mile trimmed to $7,122.

Interruptions caused by Animals or Accidents

This combined category includes animal damage as well as damage caused by automobile collisions with power poles. It makes up the next greatest number of interruptions statewide. Birds and squirrels are the animals most likely to bridge conductors and create faults. Conductor distances can be widened (at considerable expense) and animal guards can be placed on equipment to thwart bridging.

To reduce the likelihood of collisions with power poles, utilities work with local traffic enforcement and public works agencies to identify high accident locations and vulnerable poles. Solutions include installation of guardrails and relocation of equipment.

Other Causes of Interruption

The “other” category combines numerous causes, including operating error, electrical overload, vandalism and faulty installation. For most utilities, these categories each represent less than one percent of total interruptions. However, categories called “unknown” and “other – unspecified” are also included and represent a significant number of interruptions for some utilities. The agencies did not determine what all may be included in these categories. Five utilities provided data that indicated they track causes by weather - wind, rain, ice/snow and lightning. These were also included in the “other” category for this report, and represent a significant number of interruptions for some. For all the reasons above, the “other” category can be quite large (10% statewide, 6% West-side, 30% East-side.)

8.3.2 Engineering Performance Perspective: Power Quality

Power quality refers to the voltage and frequency characteristics of delivered power. It is similar to the “product quality” of more standard commodities. Delivered electricity must meet certain stringent specifications to do its work without damaging utility or end-use equipment.

Microprocessors are especially sensitive to excursions in electric voltage and frequency. With the proliferation of computers, sensitivity to power quality is increasing in homes and businesses. It is no longer just the concern of industries with mainframes and sophisticated production equipment.

For various reasons, including both practicality and cost, utilities generally have not monitored voltage and frequency at the customer level.[10] We cannot say what the actual level of power quality reliability is on utility systems, let alone observe a trend. As a surrogate for actual system measurements, the agencies asked utilities to provide statistics on measures that might be indicators of the level of power quality, including: power quality complaints by customers, power quality problems identified and solved and claims made and damages paid for power quality problems.

Unfortunately, this information is also not generally tracked, except by a few utilities. Six utilities reported the data did not exist or were not readily available for any of the questions: three provided responses for every question. In most every case, the utility has staff that respond to power quality complaints and most of their work is with industrial customers. However, to date, records are not adequate to determine whether residential power quality problems might be on the increase.

Four utilities report tracking power quality complaints (two began the effort within the last two to five years). No clear trend is evident. Three utilities track complaints by type of event (voltage sag, flicker, etc.), one tracks complaints by type of problem (long secondary, bad connection, etc.). Even for these utilities, record-keeping practices are not yet sufficiently detailed to identify increases in power quality complaints. A customer may call to complain about a surge that caused loss of data in a computer. If the utility knows there were lightning strikes in the area, the fault will likely be blamed on circumstances beyond the utility's control and no record will show that this was a power quality complaint versus an interruption complaint. Several utilities report that they think residential power quality issues are on the increase and they are instituting tracking mechanisms in 1998 for the first time.[11]

The WUTC maintains a record of the complaints it receives from customers of investor-owned utilities. More often than not, the agency is contacted after direct contact with the utility fails to result in a response satisfactory to the customer. Therefore, the database of WUTC complaints more accurately represents instances of unsatisfactory dealings with companies rather than the nature of power problems. A review of complaints from 1993 through 1998 revealed no trend in the quantity or nature of complaints. The number of power quality complaints per year has been modest (five to 14).[12]

Utility tariffs hold customers responsible for protecting appliances and equipment. Unless utility negligence can be proved, which is often difficult to do, the customer pays damage costs. Three utilities reported the type of equipment for which customers have made power quality damage claims. The list includes: computers, printers, stereos, televisions, VCRs, phones, answering machines, microwaves, refrigerators and freezers, washers and dryers, fans, garage door openers, furnace controls, heat pumps, satellite receivers, variable-speed drive motors, irrigation pumps, and compressors.

Five utilities report paying damages for power quality claims. Presumably these are instances where utility negligence was evident, or where utilities chose to settle a claim rather than pay the cost of contesting it. The data do not indicate any clear increasing or decreasing trend in damage claims. For those utilities that reported paying damages, annual reported damage payments per utility over the period of the study ranged from $4,000 to $20,000. Actual damage sustained could have been more, but is not recorded.

In summary, while power quality may be an important emerging issue, data currently available do not allow an accurate assessment of either the current level of power quality being delivered by utilities, nor any trends in that level. We discuss power quality issues in more detail in Section 8.4: Factors and Trends Affecting Electric System Reliability.

8.3.3 Engineering Performance Perspective: Generation Supply Adequacy

The first two dimensions of service reliability focus on *delivery* of electricity service. The third dimension of reliability concerns the adequacy of generation supply — is there enough generation available to meet all needs and requirements?

Generation supply adequacy in the Pacific Northwest involves several time dimensions. Is there enough water in the region's reservoirs at the beginning of the winter peak season to ensure an adequate supply of generation late in the season? Is there enough water in the reservoirs each day to meet 10-hour sustained peak demands? Is there enough peaking capacity, including demand management schemes such as interruptible power supply contracts, to meet the highest peak on the coldest day of the year?

In our region, reliability problems stemming from generation adequacy shortfalls are most likely to occur late in a cold winter after a year or more of lower than average rainfall and snow pack. In this scenario, heavy winter demand depletes already low reservoirs. The failure of one or more large plants in the region could then trigger a situation where the resulting shortfall exceeds the ability of the transmission system to import sufficient replacement power to meet all customer needs. If the shortage were expected to last for a significant length of time, the state would respond by implementing a customer curtailment plan that would first call for voluntary, then if necessary, mandatory reductions in energy use.[13] While a plan exists to address this situation, no such curtailment has ever been necessary in Washington.

Planning for adequate generation has historically been carried out on a regional basis as well as by individual utilities. Utilities that own generation and operate control areas generally forecast demand in the areas they serve and either build or contract for enough generating capacity to meet that demand under an assumed worst-case scenario, e.g., arctic conditions in a drought year. BPA is legally obligated to meet all net loads of Northwest public and investor-owned utilities. Small public utilities have generally placed their total load on the federal system. Since the passage of the Northwest Power Act in 1980 planning for the federal system has been carried out by the Northwest Power Planning Council.

However, with the introduction of competition to the power generation market and with uncertainty about the obligations of utilities in the retail electricity market the potential exists for utilities to alter the way they plan for adequate generating capacity. In particular, there is concern that utilities will be reluctant to secure new generation resources because of uncertainty about their obligations to retail customers when those customers may be granted the right to leave their systems. A number of utilities raised this issue as a concern during the information gathering process for this study.

There is also a question about whether BPA's historical responsibility to meet the net loads of Northwest utilities is appropriate in an era of wholesale competition. Some believe that the federal government should avoid competing with private utilities and power sellers whenever possible, and would like to limit BPA's role in the market by restraining its ability to acquire new generating resources. Others, including utilities that place all of their load on BPA, would like to see BPA continue to acquire resources to meet their needs.

With open access to the transmission system, BPA's customers have no obligation to continue to place their loads on the federal system. This significantly raises the risk to the federal government of new resource acquisition, since there is no longer a guaranteed market for any generating resources BPA may acquire. As a result of these pressures, the governors' Comprehensive Review recommended that BPA refrain from acquiring new resources except on a bilateral contract basis. BPA's recently proposed power subscription plan follows this recommendation.

There is some indication that these changes might result in supply shortages in the Northwest. BPA's 1997 Pacific Northwest Loads and Resources Study, known as the "White Book", projects that the region could experience a shortage of up to 7000 MW of peak generating capacity during winter months under extreme drought and arctic weather conditions.[14] Much of this shortfall is on the federal system and could result in an electricity shortage of as much as 2000 aMW. This study has sparked a good deal of concern around the region, and the Northwest Power Planning Council has recently begun a study of the region's generation adequacy.

In the absence of any changes in utilities' obligation to serve, utilities retain the responsibility to ensure that adequate resources are available to meet their customers' loads. However, utilities do not all hold the same view of this obligation. Information gathered from 16 utilities indicates that the 10 largest believe that they have the obligation to ensure that adequate generation supply is available to meet customer loads. The 6 that do not believe this is their obligation state that it is either BPA's responsibility (4), or that it is the responsibility of the customer and the market (2). Even among those large utilities who believe they do have an obligation to ensure adequate generation, there is ambiguity in the scope of this responsibility. More than half — 6 of the 10 – indicated uncertainty about the extent of their obligation to customers who select "open access" service.

Those utilities that indicated how they plan for generation adequacy did not report making major changes over the last few years in the planning criteria used. Most utilities continue to plan to meet peak load under arctic weather and extreme drought conditions. Only one utility reported that it had changed the way it plans for generation resources to rely more heavily on purchases of capacity from the wholesale market.

8.4. Factors and Trends Affecting Electricity System Reliability - Issues Discussion

Electricity reliability in the near future will be strongly influenced by two key factors: competitive pressures and institutional uncertainty. These factors are affecting all sectors of the electricity industry including power generation, transmission and local distribution.

Competition has both benefits and costs. On the benefit side, competition encourages innovation and aggressive pursuit of cost-reductions in all the industry sectors. It also encourages expansion in the choices provided to customers, be they utilities buying power from generators, or consumers buying service from utilities. Some of these benefits are due to technological and fuel market changes that may have appeared regardless of the introduction of competition to electricity markets. On the negative side, reduced revenue and the need to cut costs is forcing utilities to test the limits of their transmission and distribution systems, which may lead to reduced reliability.

Fundamentally, reliability is a function of investment; investment in generating, transmission and distribution plant, and investment in operations and maintenance. Competition and the prospect of competition are spreading through the industry. At the same time, uncertainty is growing regarding obligations and opportunities for both generators and local distribution utilities. That uncertainty makes investment risky, even if it is needed to maintain reliability. Both utility and non-utility power plant developers may be reluctant to invest in new generation capability if they do not know who they will be obligated to serve or what customers will be available to buy their output. Utilities may be reluctant to invest in needed maintenance or facility replacement if they are uncertain about from whom they will be able to recover the cost of this investment. Clarifying institutional responsibilities, obligations and rules is likely to moderate concern about these risks and remove disincentives for needed investment.

This section discusses the relevant issues and trends in three industry sectors:

1. Local Distribution (maintenance, replacement, and expansion)
2. Transmission (system control, maintenance, and expansion)
3. Generation (power plant development)

8.4.1 Factors and Issues Affecting Reliability: Local Distribution

Factors Affecting Distribution System Investment

Distribution companies have the responsibility for investments to maintain, upgrade and expand distribution system infrastructure. Reliability is a function of those investments. Uncertainty about recovery of the costs incurred for distribution infrastructure represents risk that can act as a disincentive for needed investment. Risks may be highest in areas where customers may bypass the utility facilities, or where some existing or new customers are especially expensive to serve.

The more likely a customer is to bypass, the higher the risk to cost recovery. In some areas, particularly along service boundaries, the probability of bypass is highest and utilities may be reluctant to make investments there. Service territory policy in Washington does not preclude such bypass and utilities report instances of one utility courting another utility's customers.[15] Competitive pressure from the wholesale power market and access to transmission systems through FERC jurisdiction may increase this level of risk. Lack of clarity in distribution system obligations and territorial rules increases the risks to cost recovery and may serve as a disincentive for investment.

Utilities also report that connecting and serving some customers or areas can involve costs significantly higher than average. Because rates reflect average costs, serving these customers and areas raises the rates for everyone. In an effort to keep service costs as low as possible and reduce the risk to cost recovery, utilities may turn to less generous line-extension policies, or may try to avoid serving some areas altogether. Again, lack of clarity in distribution company obligations and prospects for cost recovery may act as a disincentive for utilities to make necessary investments in reliable infrastructure.

These uncertainties add pressure to cut costs and may erode the ability of distribution companies to make the investments required to provide reliable service to all customers.

Objectives of Distribution System Reliability Investment

Presuming investments in the distribution system are made, utilities must evaluate and balance investment alternatives, many of which involve reliability tradeoffs. For example, paying more for labor may leave less for equipment. Underground lines fail infrequently but the outages last longer - reducing SAIFI but increasing SAIDI. Automatic reclosers keep faults from turning into long interruptions, decreasing SAIDI but increasing the number of sags, surges and momentary interruptions. Utilities must weigh and balance the options available in each circumstance. No single solution, such as under-grounding, is everywhere appropriate. The best alternative for an individual project may include a number of options: e.g. one mile of underground, two miles of aggressive tree trimming, three miles of tree wire. Making the right choice involves complex analyses. However, we can see from the data that there are key areas of investment that every utility makes.

Key Reliability Investment - Storm Response

We noted earlier that storms are the cause of a significant proportion of Washington's service interruptions. Improving system condition and reducing vulnerability to trees can help defend the distribution system against storms. This is primarily accomplished through good planning, operations, maintenance and vegetation management programs.

Being prepared to respond to storm damage can lessen the impact of storms by reducing the length of outages. While all utilities have procedures for dealing with contingencies, preparedness can vary greatly. There is no single correct way to address an emergency. However, some basic components must be addressed in any emergency preparedness plan. These include:

- ❖ C Damage to Company Facilities
- ❖ C Storm Anticipation
- ❖ C Emergency Ramp-Up and Emergency Operations Center Activation
- ❖ C Command and Control
- ❖ C Restoration Priorities
- ❖ C Material and Personnel Resources
- ❖ C Information Management and Communication
- ❖ C Interagency Coordination

A review of the details of utility preparedness is beyond the scope of this study. However, utilities were asked to provide copies of contingency plans to make a general assessment about preparedness documents. The plans vary greatly in both scope and detail. Five utilities have no written plan. Those that do, have plans that vary from a few brief pages to sophisticated documents that address all of the components listed above. Taken alone, even a good plan is no assurance of a good response. Even sophisticated plans may have flaws and be poorly implemented.

Data management capabilities are fast becoming the key to improving response times. Utilities are more able today to identify faults from operations centers and to implement appropriate response efforts more quickly. Automatic system monitoring and switching equipment lets operators do from a distance what used to be done in the field. But utilities vary greatly in their information management capabilities. Some still have no automatic switching equipment.

Utilities often must rely on contract crews to assist in emergency response. While contract crews may have skill equal to regular employees, they lack knowledge of specific distribution systems. This could lead to increased restoration times during emergencies. For various reasons, including reduced growth, some utilities have reduced the number of employee crews over the study period.

Key Reliability Investment - System Maintenance

The fact that failure of installed equipment is the largest single cause of interruptions on both sides of the state underscores the importance of maintenance. Distribution system equipment is unusual, in that there are almost no moving parts. Equipment life is primarily a function of temperature and age. Lightly loaded equipment in a mild environment can last a long time. Heavily loaded equipment in severe conditions wears faster. Equipment nearing the end of its life is the most vulnerable to weather and other contingencies.

Maintenance consists primarily of monitoring equipment and repairing or replacing it before it fails. Manufacturing specifications, industry standards and utility experience are the bases on which maintenance is conducted. Each utility establishes its monitoring, repair and replacement procedures based on available resources and the amount of risk it is willing to incur. Utilities differ in the degree to which they allow equipment with reduced life expectancy to remain on the system. More rapid replacement reduces failures, but it is more costly. Wood poles may be inspected every five years or they may be inspected only every 15 years. Some utilities have no centralized, routine basis for pole inspection at all. Some conduct infrared inspection of overhead conductors annually, while others check only priority locations. Some may conduct infrared scanning only infrequently, if at all. Many utilities inspect equipment on a time-scheduled basis regardless of the different conditions equipment may be subject to. Others prioritize inspection of equipment based on risk analysis - key equipment is inspected more often, or may be replaced sooner.

The fact that much of our distribution infrastructure is growing old is a key issue affecting distribution system maintenance. The current stock of installed poles contains many that were originally erected fifty or more years ago. Yet, neighborhoods are now more densely populated and old equipment is being more heavily loaded.

Over the period of the study, most utilities reported an increase in maintenance expenditures. However, not all increases kept up with the rate of inflation. On a per-customer basis, expenditures did not keep pace with inflation for a majority of utilities. Table 8.4 lists the number of utilities for whom reported maintenance expenditures represent an increase or decrease over the period 1990 to 1997. Adjustments are made to reflect inflation and changes in the number of customers served. The greatest increase in non-inflation-adjusted expenditures was on the order of 14 percent, the greatest decrease (minus) 1 percent. The greatest per customer increase was 10 percent, the greatest decrease (minus) 3.3 percent. .

Declines in per customer expenditures may reflect an increase in customer density, where it costs less to provide the same level of service per customer. Our information does not contain enough detail to examine specific maintenance practices, for example, to examine whether shifts have occurred between equipment purchases and labor.

Table 8.4: Number of Utilities with Increased or Decreased Maintenance Expenditures over Study Period[16]

Maintenance Expenditures	Increase	Decrease
Total (Nominal Dollars)	11	2
Total (Versus Rate of Inflation)	7	4
Per Customer (Versus Rate of Inflation)	4	7

Source: Data reported by utilities to 6560.

The data in Table 8.4 suggest that, in general, utilities are not greatly increasing or decreasing their maintenance expenditures. Expenditures for most utilities are a few points above or below inflation. Nevertheless, the stated concerns of utilities about competitive pressures and the future ability to make needed investment in the distribution system should be taken seriously. Equipment, operations and maintenance costs are all candidates for reduction in a cost-cutting environment.

Across the country, some state governments have taken the step to set maintenance standards for utilities, including California, Oregon, Pennsylvania, Iowa and Kentucky. Standards primarily address monitoring cycles, testing specifications and repair and replacement criteria. Also in California, the California Independent System Operator (CAISO), which operates the state's transmission grid, has been granted statutory authority to sanction utilities that cause problems on the transmission grid. The CAISO has responded by requiring utilities to monitor in great detail all aspects of their transmission maintenance programs. In the future, poor maintenance practices and reduced expenditures may be used as evidence for assessing penalties and sanctions in California.

Key Reliability Investment - System Expansion

Utilities continually redesign and expand their systems to address new development and increasing density on existing circuits. There is no easy way to evaluate whether criteria or standards for system construction have changed over time. Declining standards could lead to higher system loading. Under traditional regulation and local rate-setting, utilities operated with the expectation of a reasonable return on prudent investment. In some cases, this led to suspicions of gold-plating; installing premium equipment whether or not it was necessary. In addition, utilities built many lines anticipating future load. These two factors have led to what appears to be a general industry perception that past infrastructure was somewhat over built, though perhaps more reliable because of it.

System construction upgrades and expansions are designed, built and inspected by the utilities themselves. Utility plant is expressly exempted from the National Electric Code (NEC) that covers all other electrical construction and is enforced by the Department of Labor and Industries (L&I).[17] Utilities *are* subject to the National Electrical Safety Code (NESC) and L&I may inspect utility plant for compliance with public and worker safety standards. The safety standards are performance-based; meaning that installed equipment must meet standard performance criteria under standard conditions. However, the choice of what equipment to install is up to the utility, not specified by the NESC, and there are no specific standards related to service reliability.

Utility system design, construction and expansion in the future will face opposing trends. Technological improvements, including promising distributed generation alternatives, may make reliability cheaper and easier to attain in design and construction. The drive to cut costs and deal with obstacles to construction may make it more difficult. Utilities report increasing difficulty and costs in attaining access permits necessary to construct new lines and equipment. The public may generally value reliability yet oppose new construction that would provide it, especially if it is "in their backyard."

Key Reliability Investment - Vegetation Management

Utilities on both sides of the Cascades report large numbers of tree-caused interruptions. Most of these are weather-related. Wind, rain, ice and snow force trees and branches into lines. A branch that simply settles across two lines causes a fault. Second to maintenance, vegetation management is probably the most important reliability program for most utilities, clearly for those west of the Cascades.

The primary focus of vegetation management is trimming or removal of trees that may cause system damage or a ground fault. Programs usually have an operations component that addresses immediate problems and a preventative maintenance component that manages feeder and lateral lines on a cycle. Most utilities trim on a full system cycle (every feeder is trimmed every 1 to 4 years depending on the utility). Some utilities use a number of criteria, such as tree type and customer density, to set different cycles for different areas. For example, rural feeders lined primarily with coniferous trees may need to be trimmed only once every six to ten years. Urban feeders lined with deciduous trees, especially certain fast growing types, may need to be trimmed every two years. Utility tree trimming crews are usually solely dedicated to vegetation management. Crews may be utility employees, but the trend is for utility personnel to manage a program that relies extensively on contract crews.

There is no uniform standard for vegetation management programs. Utilities develop their own criteria for trimming cycles, trimming distances and tree removal. Across the nation, some states have established vegetation management standards. California and Oregon, for example, require utilities to trim all trees within a certain cyclical period. California, in addition, has prescribed a year round, minimum distance between branches and lines, regardless of trimming cycles.

Table 8.5 includes the number of utilities for whom vegetation management expenditures increased or decreased between 1995 and 1997. Comparisons are adjusted for inflation, number of employees (FTE), and number of distribution system miles cleared. Over the period of the study, most utilities increased their annual expenditures for vegetation management. For 10 of 16 utilities the increase was greater than inflation. Most utilities also reported an increase in both dedicated staff and annual miles of distribution line cleared. As a result, for 6 of 13 utilities, expenditures per mile cleared decreased (for 9 if inflation is taken into account).

Table 8.5: Number of Utilities with Increased or Decreased Vegetation Management Expenditures over Study Period.

Expenditures	Increase	Decrease
Total (Nominal Dollars)	12	4
Total (Versus Inflation)	10	6
Per FTE (Nominal Dollars)	11	2
Per FTE (Versus Inflation)	3	10
Per Mile Trimmed (Nominal Dollars)	7	6
Per Mile Trimmed (Versus Inflation)	4	9

Source: Data reported by utilities to 6560.

Most utilities' expenditures are a few points above or below inflation. It appears that, in general, utilities are maintaining about the same level of effort over time. However, reductions in expenditures per employee and per miles trimmed could reflect increases in productivity, changes in trimming requirements, or reductions in program quality.

Over the last three years, statewide tree-caused interruptions have decreased from 30 to 20 percent. The ten-percentage point decrease is primarily due to reductions in tree-caused interruptions for two West Side utilities. These utilities faced some serious storms during that period and it is difficult to know whether the reduction is mainly weather-related.

Tree trimming alone does not address all the variables that influence tree-caused outages. Development practices that leave thin stands of trees abreast power lines are an invitation to tree-caused outages. Thin stands are not protected from wind, as are denser forest stands. Compacting and paving land results in increased water runoff that can erode the base of tree stands, making the trees more vulnerable to wind-throw. Over the last two decades, western Washington has experienced relatively rapid population growth and suburban development.

If utilities are kept informed, they may be able to coordinate with other parties and projects involving tree cutting or tree removal. Tree removal often requires approval of a Forest Practices Application by the Department of Natural Resources (DNR). However, environmental criteria consume the bulk of DNR's approval and enforcement efforts; power issues are not high on the list. Though the application provides notice to the applicant that they must notify the utility if any trees are within two tree lengths of a power line, utilities report that they often are not notified.

Finally, urban vegetation management also presents some challenges. Utility right-of-way is often very narrow and may be squeezed between roads and city or private property. A single mile of right-of-way may include some utility property, city easements and a large amount of private property. Utilities must work with each property owner, and many, including cities, are not eager to have their trees cut. Utilities do not have authority to trim against an owner's wishes.

Key Reliability Investment - Power Quality

Power quality was once the exclusive concern of industrial customers. There is growing evidence that residential and commercial customers should be equally interested. Utility tariffs make customers responsible for the protection of their own equipment.[18] Customers who do not know this may find out too late at considerable cost.

Power quality standards primarily regulate electricity voltage and frequency. Authority to set reliability standards resides in the general regulatory authority of utility governing bodies granted by state law. By rule, each investor-owned utility must set a standard frequency and voltage, which are then subject to minimum and maximum excursions.[19] The governing boards of publicly-owned utilities set their own standards. While all utilities deliver a uniform 110 volts to customers, they operate their distribution systems at higher voltages that may differ from utility to utility. All utilities in North America operate their systems at the same frequency: 60 hertz (60 cycles per minute).

Standards are set, in part, to protect customers from utility negligence. Utility operating activities and maintenance practices can cause voltage and frequency problems. For example, overloaded equipment may fail before scheduled replacement. Tree branches that are not properly trimmed may bridge lines when the wind blows. But, negligence can be very hard to prove. Voltage and frequency can only be measured at specific places and times with equipment designed for the purpose. It is costly to locate such equipment everywhere around the grid, so the grid is not continually monitored.[20] This means it is often difficult to know what the nature of an excursion was, let alone what caused it so that responsibility can be determined.

Standards also are set to protect utilities from circumstances beyond their control. Environmental conditions like wind, lightning, ice, snow, and sunspots all affect the quality of power delivered over utility distribution systems. Utility regulators and local governing bodies recognize the difficulty of maintaining grid standards under all conditions. Therefore most standards are qualified to allow considerable excursions to occur. For example, investor-owned utilities are required to maintain frequency "*reasonably* constant," and maintain minimum and maximum levels only under "normal operating conditions," (emphasis added).[21] Such qualifications permit frequent excursions from the standard to be the norm.

The degree to which off-specification voltage and frequency causes problems is a function of the nature and magnitude of an excursion and the sensitivity of the conductors and equipment involved. Small sags can bring expensive production equipment to a grinding halt. Large surges may only affect a few transformers. Many power excursions cause only inconvenience; lights flicker, clocks stop and computers reboot.

But, equipment sensitivity is growing. Microprocessors are especially sensitive to power excursions. Critical applications, such as financial transactions, security monitoring and production processes increasingly rely on sensitive electronic controls. Even in the home, computers, entertainment systems and heating and cooling controls may be sensitive to power quality. Manufacturers are producing increasingly sensitive equipment, which we are using with increasing frequency for critical applications. So, even if the reliability of power quality remains constant, we can expect power quality problems to increase.

Sensitive equipment can, in many instances, be protected with devices designed for the purpose, such as external surge protectors and uninterrupted power supply systems. Whole-house surge protectors that protect the entire home have been advertised recently. For industrial applications, a new power quality industry has arisen, with consultants recommending sophisticated new power regulating equipment to protect factories and offices. This means that power quality reliability can be achieved at the customer's site and expense, rather than on the distribution system at ratepayers' expense. Customers with special needs or wants have always been able to secure high reliability at a price. In the past, however, this was usually the concern of industrial, not residential, customers.

Key Investment - Year 2000 Compliance

The Year 2000 (Y2K) problem poses a momentous challenge for the electric utility industry. The complexities and uncertainties surrounding Y2K have so far kept utilities from guaranteeing reliability, which has fueled speculation that there could be widespread and long-lasting power outages at the turn of the century. Most utility executives believe, having seen the early results of testing, that major outages can be avoided, but they admit that minor outages may occur. Because all sectors of society depend so heavily on electricity, there is no more important industry to become Y2K compliant.[22] The state and utility governing bodies are well aware of this and have put into place comprehensive plans to ensure compliance.

There is no single compliance plan covering all Washington utilities and no single organization that is coordinating utility efforts. Instead, depending on the size and nature of their system, each utility is working with numerous organizations. Eleven key utilities that operate transmission control areas under the Western Systems Coordinating Council report compliance progress to the National Electrical Reliability Council. Investor-owned utilities submit quarterly reports to the WUTC. The BPA has taken a lead role in coordinating the efforts of its customers. Cooperatives, municipal utilities and PUDs are coordinating with key associations such as the Association of Washington Cities and the Washington PUD Association. The Northwest Public Power Association is considering implementation of an Electric Power Research Institute (EPRI) compliance program for member utilities. Utilities also are cooperating with the state Division of Emergency Management to coordinate contingency planning.

Working toward compliance generally means taking the following steps: inventory (accounting for all utility devices), assessment (determining the vulnerability of each device), testing, remediation (applying a solution), and retesting. Steps are worked in parallel, though there is a natural order to the process. Most utilities have completed or are progressing on inventory and assessment and have begun the testing phase. Testing has already revealed control and communications vulnerabilities that, if left uncorrected, could have caused major outages. On the positive side, at least one large Washington utility has completed testing nine of 12 generating plants and has found few significant compliance problems. However, many utilities are not so far along and far more than generating plant must be tested. According to EPRI, a moderately sized utility may have as many as 30,000 devices with failure potential. As compliance testing intensifies in 1999 and test data become more available, we will have a much better understanding of our reliability risk in the year 2000 and what needs to be done to prevent or minimize the impact of failures.

8.4.2 Factors and Issues Affecting Reliability: Transmission System

Most of this chapter has focused on reliability of distribution systems. This section focuses on the reliability of the interstate transmission grid, otherwise known as the bulk power system. The bulk power system consists of generating units, transmission lines and substations and system controls. Although the transmission system has historically been responsible for only a small percentage of all power outages, the scope of such outages are usually much broader than those caused by distribution system failures. Bulk power outages may have regional implications and impact many utility distribution systems. [23]

There is no clear distinction between which facilities are transmission and which are distribution. High-voltage facilities (230 kV and above) whose main purpose is transmitting bulk power over long distances are clearly transmission. Low voltage facilities (12.5 kV and below) whose main purpose is transmitting power to individual homes and businesses are clearly distribution. The facilities that fall in-between are known as sub-transmission and can be classified as either transmission or distribution, depending on their primary function.

Utilities began to interconnect their transmission systems early in the century as plants became larger and began to be located at greater distances from the loads they served. As decades passed, an increasing number of generators, transmission facilities and load centers were interconnected over increasingly large areas. Expansion of interconnecting transmission systems in the western United States and Canada resulted in the complete interconnection of the western system during the mid 1960s. These changes required increased coordination and planning among utilities to maintain reliability.

In 1965, a blackout in the northeast U.S. that left almost 30 million people without electricity triggered national concern about the reliability of interconnected bulk power systems. This concern resulted in the formation of ten regional reliability councils, including the Western Systems Coordinating Council (WSCC). The WSCC is a voluntary organization made up of electric utilities that are engaged in bulk power generation and transmission in the western interconnection. The WSCC region encompasses electric systems serving all or part of 14 Western States, British Columbia and Alberta, Canada, and Baja California Norte in Mexico. The ten regional councils created the North American Electric Reliability Council (NERC) in 1968 to coordinate the efforts of the regional councils, to set national standards for electric system operation and to monitor voluntary compliance with those standards.

The primary concern in operation of the interconnected transmission grid is maintaining system "security." Security refers to the ability of an electric system to withstand sudden disturbances. The sudden loss of a generating unit or transmission line can lead to rapid changes in voltage levels and frequency that, left uncorrected, could damage equipment of both utilities and customers. In some cases, these disturbances can lead to other disturbances elsewhere in the system, taking down generators and transmission lines one-by-one in what is referred to as a cascading outage. Preventing these is the work of regional grid management organizations such as the WSCC.

This system of securing reliability through voluntary compliance with industry-established rules has worked well for the past 30 years. However, the electric industry is changing in a number of ways that are making the current system of voluntary compliance increasingly untenable. First, the Energy Policy Act of 1992 and FERC's Orders 888 and 889 are changing the commercial relationships among users of the transmission grid. FERC is creating competitive wholesale power markets and requiring utilities to unbundle generation from transmission and provide nondiscriminatory access to all users of the grid. In response, a number of states, including California, Montana, Nevada and Arizona are in the process of restructuring their retail electric markets. These actions are creating substantial changes in the character of participants in bulk power markets. Transmission operations were far less complex and more secure when operators had both access to system information *and* control of generating resources. Those capabilities have been separated. Second, the significant increases in the number and complexity of transactions associated with greater competition increases the chances for operating error. Third, there is increased pressure to ensure that system operators make minute-to-minute decisions in ways that do not favor certain market participants over others, because many actions taken to operate the grid under conditions of heavy use have potentially significant financial implications for market participants. Finally, the diverse market pressures facing many of the participants in bulk power markets could discourage compliance with voluntary reliability requirements.

As a result of these changes, existing electric reliability organizations have begun to reassess whether the current structure will be sufficient to ensure electric system reliability in the future. This process was hastened by two major transmission system outages in the western interconnection in 1996. While it is impossible to determine to what extent these outages were due to industry changes such as those described above, the outages brought national attention to the problem of electric system reliability in a changing industry environment.

National Developments

In August 1997, NERC assembled a "Blue Ribbon" Electric Reliability Panel to recommend the best ways to set, oversee and implement policies and standards to ensure the continued reliability of North America's interconnected bulk electric systems in a competitive and restructured industry. The panel issued its report, *Reliable Power: Renewing the North American Electric Reliability Oversight System*, in December, 1997. The report recommended the creation of a new Self-Regulating Reliability Organization (SRRO), which it dubbed the North American Electric Reliability Organization (NAERO), that would have authority to enforce compliance with reliability standards.

NAERO was launched by vote of the NERC Board of Trustees on July 9, 1998. However, key elements of the NAERO plan, including compliance enforcement and funding, cannot go into effect without federal legislation.

Western Developments

The WSCC differs from most regional reliability organizations in that it is coterminous with an AC interconnection. This means that system security problems caused by operations in the WSCC region cannot have any effect on operations outside of the region. It also means that the voluntary standards developed by the WSCC are applicable to every party whose actions can have a negative impact on WSCC reliability. This stands in contrast to the situation in the eastern interconnection, where rules and standards are developed by seven different regional reliability organizations, and each region is vulnerable to the actions of companies in neighboring regions.

The West is also unique in that it has three functioning Regional Transmission Associations, (the Western, Northwest and Southwest Regional Transmission Associations, or WRTA, NRTA and SWRTA). These organizations were developed by western interests to address commercial issues related to transmission system operation brought on by the burgeoning wholesale electric power trade. In the eastern interconnection, commercial issues are addressed primarily by NERC.

These factors have resulted in a unique set of institutional relationships in the western interconnection. Solutions to transmission system operational issues, related both to reliability and commercial interests, have traditionally been devised and implemented on a consensus basis within the western interconnection, with a minimum of oversight from outside parties. Because of this tradition, some in the West have resisted the development of a new, national reliability organization with enforcement powers and have called instead for the creation of a separate Self Regulating Reliability Organization for the western interconnection that would be independent from NAERO.

Discussions have been taking place during 1998 under the auspices of the Western Interconnection Forum (WICF), an ad-hoc, umbrella organization created by the WSCC and the three RTAs to discuss the future roles of regional grid-management organizations. Key questions being raised include: whether the western interconnection should form its own self-regulating reliability organization that would be independent of NAERO; what kind of governance, funding and authority a new western grid management organization should have; and how reliability and commercial interests should be weighed when making decisions about the operation of the regional transmission grid. It is unclear at this writing what direction these discussions will ultimately take. Attempts are being made to foster a unified Western position so as to maximize the region's bargaining position when Congress debates the issue of mandatory reliability standards in 1999. It is likely that some form of SRRO will eventually be legislated by Congress, but it is too early to predict exactly what form that entity might take.

Formation of an Independent Transmission Operator

Some in the industry believe that all utilities will ultimately be required to divest either their generation or their transmission assets. They believe it will prove too difficult to enforce codes of conduct governing relationships between generation and transmission subsidiaries of a single company and point to the experience of the natural gas industry, where FERC required divestiture of pipeline assets. A related alternative is to require divestiture of all transmission assets and formation of an independent operator to run the transmission system. While arguments in favor of the formation of independent operators rest primarily on economic grounds, e.g., mitigation of vertical market power, many believe it would enhance the reliability of the bulk power system.

There are several reasons for this belief. First, many believe that the reliability of the interstate transmission system would be best protected by an entity with a neutral position in the generation market. If the operator's primary mission is to operate the transmission system reliably, the argument goes, the operator is less likely than is a vertically integrated utility to engage in activities that may benefit a subsidiary while degrading the reliability of the bulk power system. This is most likely to be the case if the effect of an outage would be felt by customers of a competitor, perhaps in a neighboring state.

Second, an independent operator may also be better positioned to safeguard reliability because its system operators would know about all major events that occur on the regional system. One of the factors that exacerbated the 1996 outages was that not all system operators were made aware of the seriousness of the problems in a timely manner. An independent operator would be connected electronically to generators and transmission lines throughout the region, and might be better able to isolate a potential problem than today's system of dozens of control areas. An independent operator would also have knowledge of all generation-to-load schedules across the regional bulk power system. This might give it the ability to better monitor potential trouble spots. Independent operators now operate several systems in California and the Northeast.

8.4.3 Factors and Issues Affecting Reliability: Generation System

Earlier sections of this report have discussed the development of a competitive market for power generation. Prior to the 1978 Public Utility Regulatory and Policy Act, utilities were solely responsible for construction of adequate generation facilities to meet customer loads. Trade in electricity did occur, but mainly between utilities for purposes of efficiently using existing capacity. Non-utility generators entered the scene through the 1980s and were joined by a broad and diverse set of wholesale generators, marketers, and power brokers after the Energy Policy Act of 1992. As a consequence, trade in wholesale power has grown substantially[24] and utilities no longer face the need to construct their own power plants to meet customer loads. They now have the ability to purchase electricity generation from market sources at prices set by competition.

Traditionally, utilities have maintained a “reserve margin” of generation capability to ensure that sufficient generation will be available to meet load even if some part of the system fails. Increased reliance on markets may reduce this margin, making the region more vulnerable to contingencies. This is not necessarily a bad thing. Traditional margins of 20 percent or more have meant that one-fifth of the region’s generation plant is left idle during most hours in anticipation that it might be needed to respond to an emergency. This is an expensive insurance policy, and if utilities have overestimated customers’ desire for reliable power supply, then lowering reserve margins will save costs and bring the supply and demand of peak generating capacity closer to balance.

There is another reason why utilities might allow reserve margins to fall, however: uncertainty about what their retail load will be and what their obligations will be vis-à-vis that load. This uncertainty stems from at least two sources: the potential for physical bypass of the utility’s distribution system, and the potential for new state or federal laws that grant retail customers access to the market.

The threat of physical bypass, i.e., construction of redundant power delivery lines to access service from another utility, has always been an option for customers who have practical opportunities to do so. Only recently, however, with transformation of the high voltage transmission system into an open-access common-carrier and the emergence of a competitive wholesale power market with numerous suppliers, has the attractiveness of this option increased to the point where it might be affecting utilities’ willingness to invest in new generating capacity.

Of greater concern for many utilities is uncertainty about retail market structure. Developments at the federal level and in neighboring states such as California, Montana, Nevada and Arizona have created uncertainty about the retail market structure in Washington. Faced with the possibility of losing customers to competition from other suppliers, utilities are reluctant to make long-term commitments to new supply, especially when they can purchase generation on the wholesale market on a monthly, daily, or even hourly basis. This reluctance to make long-term commitments could result in delays in the construction of needed generating capacity.

Another trend that could potentially have an impact on generation supply adequacy is the increasing prominence of independent, non-utility power providers in the wholesale market. These non-utility developers are building most new generating capacity. The utilities themselves have placed a number of prominent utility-owned power plants in the region up for sale. These include the Centralia plant, currently owned by a consortium of eight Northwest utilities, and the shares of the Colstrip plants in Montana belonging to Puget Sound Energy, PacifiCorp and Montana Power.[25] These utilities are likely to replace these generating resources with power supply contracts from independent power providers.

The emergence of independent power providers as a major player in the wholesale generation market does not necessarily constitute a threat to reliability. As long as they have the ability to obtain long-term power purchase contracts with utilities, independent power providers should have the same incentive as utilities to build sufficient generating capacity and operate it reliably. However, we have already seen that utilities may be increasingly reluctant to engage in long-term commitments. This problem stems from uncertainty about retail market structure and would exist regardless of who builds generating capacity. However, to the extent that independent providers face greater risk than utilities in constructing new capacity, the effect may be amplified.

Another issue associated with independent power providers is credit-worthiness. Market transactions rely solely on contractual commitments. While contracts establish obligations and responsibilities, they are also subject to default if companies do not have the financial resources to fulfill their obligations. This is not an abstract possibility. The electricity shortages and price spikes that occurred during the heat wave in the Midwest U.S. this past summer were aggravated by the default of an independent power provider, and the inability of its guarantors to deliver on their obligations. Such a collapse of market arrangements need not result in interruptions in power supply, as long as sufficient generating capacity exists AND the operator of the transmission system has the authority to order idle generators into service. If either of these two conditions fail to hold, load would have to be shed in order to keep the system in balance.

Despite the uncertainties described in this section and elsewhere in this report, some new generating capacity has come on line in the region during the past few years. Several hundred megawatts of new, natural gas-fired generation were added by utilities and by non-utility developers with long-term utility contracts. In addition, over 3000 MW of new facilities have been issued site licenses (permits to construct) or are in the siting process in Washington, Oregon and Idaho.[26] For the most part, these site licenses or applications involve non-utility developers. No construction is currently underway on these sites.

The experience in California, where retail markets have been restructured, may also be instructive. The California Energy Commission (CEC) reports that it anticipates receiving applications to site some 7000 MW of new capacity.[27] At the same time, however, the CEC has performed analyses suggesting that prices on the California

Power Exchange during its first six months of operation have not generally been high enough for investment in new generating capacity to be profitable.[28]

These developments indicate that many of the site licenses and applications in the Northwest and in California may be speculative. In Washington, no construction has taken place on some 1650 MW of capacity granted site licenses over the past few years. Site licenses are held by non-utility, private developers who will make decisions to actually begin construction based on their expectation of the price that power from these plants will receive in the competitive power market. The question of whether facilities will be built in time to meet the needs of growing demand, or, more importantly for the Northwest, to prepare for the contingency of poor water years, remains unanswered.

8.5 Strategies to Ensure High Reliability in the Future

The preceding discussion documents that distribution system reliability in Washington is generally good, or at least comparable with other states and countries. However, some trends and issues associated with the emergence of competition may be putting pressure on key factors that will affect service reliability in the future. This section describes strategies and actions that could be taken to address these pressures and maintain, or even improve, reliability of electricity service. In each case we have described the strategy and its rationale, as well as summarizing arguments that could be made for or against the strategy. The strategies are organized into categories that address:

- ❖ The Distribution Sector
- ❖ The Generation and Transmission Sector

The Distribution Sector strategies are further categorized into those that involve:

- ❖ Performance Standards
- ❖ Program Standards
- ❖ Institutional and Market Issues

8.5.1 Reliability Enhancing Strategies: Distribution Sector.

Performance Standards:

1. <u>Establish Minimum Levels of Grid Reliability.</u>

Description: Mandate minimum levels of grid reliability. These standards could be uniform statewide, or be utility-specific, and could address both system interruption and power quality performance. Statewide standards would allow electricity customers to locate anywhere in the state and expect the same minimum level of service. Utility-specific standards would establish a minimum level of reliability while recognizing the geographic differences among utility service territories. Oregon has recently adopted requirements for investor-owned utilities to maintain performance records and has also established performance standards for these utilities. California has also established standards for both data monitoring and system performance. Consistent measurement and record keeping of distribution performance statistics would be required both to set and to ensure compliance with standards.

Rationale: Minimum standards act as an incentive to keep reliability at a desired level. They promote equity. Standards also allow customers to assess their electricity service requirements more accurately and plan accordingly.

Arguments For: A reasonable level of reliability is required for convenience, safety and normal business operations everywhere. All communities and customers should be able to expect a reasonable level of electricity reliability. In the absence of a consistent standard, difference among utility management strategies, investment incentives, and the relative influence of customers with specific reliability needs could lead to wide variation in service reliability from place to place. Some areas could experience significantly degraded reliability.

Arguments Against: Reliability decisions are best made at the local level. Statewide standards would usurp control from locally elected boards and impose a potentially costly mandate on service territories where providing reliable service is more expensive. Besides, both the WUTC and the governing boards of public utilities have already established minimum standards. In general, standards covering power quality are specific, but flexible, recognizing the influence of forces beyond utility control. Interruption standards are primarily descriptive, not prescriptive.[29] Present levels of reliability are reasonably good and equitable. In addition, setting stricter or more prescriptive standards may undermine the concept of appropriate reliability, i.e. providing what the customer wants. Setting a prescriptive minimum standard requires choosing an arbitrary level that for some customers may be too high.

Program Standards:

1. Require utilities to track and maintain a record of performance reliability data.

Description: Require utilities to systematically track reliability data. The nature of the data to be maintained should be clearly defined and standardized. A consistent record of reliability data would support a number of purposes ranging from public information, to utility decision-making, to evaluation of performance targets upon which incentives and penalties might be based. Oregon has recently adopted requirements for investor-owned utilities to maintain performance records and has also established performance standards for these utilities. California has also established standards for both data monitoring and system performance.

Rationale: If reasonably accurate and meaningful reliability measurements can be made, governing bodies can determine whether increased investments in reliability are warranted, customers can have a more firm basis for judging service reliability and available alternatives, and utilities can have better decision-making tools at their disposal. All of these could lead to more effective and efficient management and targeting of reliability investments.

Arguments For: Lack of consistent information makes it difficult for utility governing bodies and regulators to know what level of reliability is being delivered. More consistent and meaningful measures would allow them to track reliability over time (for improvement or deterioration), and to know how utilities compare. In addition, this would allow for better assessment of appropriate levels of reliability investment. Publishing reliability indices or other statistics would act as an incentive to utilities to maintain reliability.

Arguments Against: Utilities are very different, both in the nature of their systems and in their approach to managing reliability issues. Utilities and their governing bodies and regulators should be allowed to determine for themselves the degree to which investments in data collection and record keeping are necessary and appropriate. Intensive data management can be expensive and a utility may prefer to dedicate resources to operations and maintenance. Moreover, decisions about how performance data should be reported, to whom, and for what purposes should rest with the utility so that misinterpretation is avoided. As long as customers are satisfied, there may be no need for a utility to track reliability data.

2. Improve Customer and Public Information

Description: Require utilities to implement programs that provide better reliability information to customers and to the public in general.

Rationale: Customers who have better information about reliability will make better decisions about the types and levels of reliability that are appropriate to them.

Arguments For: Competition works best when good information is available to all market participants. Some utilities today cannot provide their customers with system-level reliability performance information, let alone sub-system or customer specific information. Regarding power quality, customers may know that it is a good idea to protect their appliances and equipment, but they may not know that tariffs make it their responsibility to do so, exposing them to significant risk.

Arguments Against: Better information is important and will occur naturally as competition between utilities grows. In the past, most utilities have not been able to provide detailed reliability information to customers because the data were too expensive to gather and manage. Such information is becoming more cost effective and as it becomes available it will find its way to the customer.

3. Establish Requirements for Emergency Preparedness Planning

Description: Require utilities to take consistent and uniform steps to prepare for response to emergencies. Steps could include: preparing response plans, meeting mutual aid standards, participating in exercises and conducting joint planning with local emergency response agencies.

Rationale: Requiring utilities to take certain proven steps to prepare for emergencies guarantees a minimum level of preparedness by all utilities. Standardization also facilitates the exchange of information improving both preparedness and response. Improved response will reduce the length and impact of storm-caused interruptions (SAIDI).

Arguments For: Emergency response does not involve guesswork. Law enforcement and fire and rescue agencies, including the military services, know what needs to be done and have developed emergency management practices that work. These include developing plans, establishing an appropriate management structure and participating regularly in exercises. These practices are all designed to prepare a responding agency to act quickly and cooperatively with other agencies, the key to success in emergency response. Not all Washington utilities currently take these steps. Requiring them to do so would improve their response capabilities and Washington's reliability.

Arguments Against: It's true that if all Washington's utilities took all these steps response capabilities would improve; but at what price? And is it necessary? There is no evidence that a small utility that doesn't have a written plan and that doesn't participate in annual exercises *needs* to improve its response capabilities. The cost of doing so uses capital that could be better spent elsewhere, perhaps on investments that would improve reliability in some other way. Individual utilities should be left to determine on their own the kind of preparedness that is appropriate for them. Emergencies are public relations nightmares for utilities and provide sufficient incentive to develop adequate response capabilities. A standard is not required.

4. Set Programmatic Standards for Key Reliability Programs such as System Maintenance and Vegetation Management

Description: Establish facility maintenance and inspection standards designed to address factors that are likely to affect system performance, such as vegetation management and system maintenance. Standards might be general, such as the requirement to have a tree trimming plan and to set trimming cycles, or they could be more prescriptive such as the requirement to trim trees within a specified time cycle and to keep branches clear from lines to a specified distance. The standards could be set on a uniform, statewide basis, or they could be set on a utility-specific basis. Oregon and California have established standards that are a mix of statewide and utility-specific programmatic maintenance and inspection standards.

Rationale: Maintenance and inspection standards ensure utilities will take specific actions that have been proven to have a positive effect on reliability.

Arguments For: A clear set of standards for system maintenance inform utilities and customers alike of what actions should and will be taken to keep the distribution system in good working order. Focusing standards on parts of the system that most affect its reliable operation should ensure that actions taken are cost-effective. Establishing state-level standards that are general and local level standards that are specific allows for local circumstances to be reflected in standard-setting.

Arguments Against: The factors that affect system reliability vary from utility to utility. Statewide standards, even if general, may not capture those issues that are most important for any particular utility and therefore may be of little value. More specific statewide standards may impose requirements that are not relevant or effective in specific local circumstances. Even if standards are set at the local level, requiring them to address specific issues may be too rigid a prescription to allow for local factors to be prioritized. Some trees do not need to be trimmed very often. Some transformers do not need to be inspected very often. Dedicating resources to do unnecessary work in order to meet a standard will mean that more appropriate work will not be done.

Institutional and Market Issues

1. Clarify Distribution Company Authorities and Obligations.

Description: Clarify utility service obligations. Establish a more definitive service territory policy. Establish a policy for addressing stranded costs associated with reliability investments.

Rationale: Clarifying distribution company obligations would allow for better assessment of the risks of various reliability investments. For example, requiring that customers who take market access and accept market risks be responsible for their own supply arrangements frees the utility from making most supply investments on their behalf. Allowing distribution companies to establish stranded cost charges or exit fees would provide greater certainty that reliability investments will be recovered. Strategies to clarify utility obligations, service territories, and conditions for market access are discussed in greater detail, along with arguments for and against, in Section 4.0

2. Set Electricity Rates to Represent More Accurately the Costs of Providing Reliable Service.

Description: Allow or require rates to be set for electricity service in a manner that more closely reflects the costs of reliability. Encourage the implementation of alternatives that allow for different levels of grid reliability and opportunities for customers to enhance the service provided by the grid at their own cost. For example, rates could include a reliability component that differed for urban, rural, island or other customers and that was set based on the cost of achieving a certain level of reliability in that area. Communities could vote on investment alternatives (such as undergrounding) that would improve their reliability and incur a portion of the cost as a rate adder. Approaches similar to this are being implemented in the United Kingdom.[30]

Rationale: This alternative would “improve” reliability in the sense that it would allow customers to experience levels of reliability suited to their choice. It would promote equity in payment for reliability rather than in level of reliability.

Arguments For: Customers differ greatly in the level of reliability they need, want and are willing to pay for. Current rate structures do not address those differences and send few cost signals to customers about alternative levels of service. Precedent for a customer-specific cost-based approach already exists in line-extension policies. This concept builds on the line-extension approach. Better pricing will encourage the implementation of reliability alternatives and an industry that delivers appropriate reliability at appropriate prices.

Arguments Against: Cost unbundling studies make clear how difficult it is to allocate costs to classes let alone to individual customers. Line extension is a distinct service, far more amenable to distinct rate treatment than reliability. Reliability is a general characteristic of the distribution system that should be priced at average cost for all customers served by the system. Electric service is essential to the economy and quality of life of all citizens of the state. Allocation of the costs of reliability to specific customers and extensive reliance on customer-funded alternatives, rather than on a universal level of reliability, will eventually limit reliable service to those who can afford it.

3 Encourage Manufacture of Equipment Less Sensitive to Power Quality Problems.

Description: Develop and implement ways to encourage or require manufacturers to produce appliances and equipment that are less sensitive to surges, sags, or other power quality problems. Federal standards and government/industry initiatives are two examples of ways to influence manufacturer practices.

Rationale: Encouraging the equipment and appliance market to produce equipment that is more forgiving of power quality variation will reduce the importance and potential expense of maintaining rigid power quality standards on the distribution system.

Arguments For: Because of manufacturing scale economies, building protection directly into a device can often be done for less money than it costs to purchase an external protective device. Manufacturers would also be more likely to know what kind and level of protective devices were required and to install them appropriately. Cost, risk and inconvenience would be reduced for the customer.

Arguments Against: Making equipment and appliances less vulnerable to power quality problems could raise production costs and prices. Manufacturers may oppose establishment of standards. Bundling such equipment in equipment and appliances may undermine the market for external equipment and the ability for customers to choose their own levels of power quality protection. An array of external protective devices has been developed in response to the sensitivity of equipment, including devices that soon may protect the entire home. If consumers value products that provide either external or internal protection sufficiently, this may provide sufficient incentive to manufacturers to solve this problem without standards.

4. Establish Reliability-Based Forest Practice Laws and Regulations.

Description: Establish policies and regulations that either disallow forest practices that place power lines at significant risk or that facilitate mitigation of risks to power lines. Ensure that power issues are addressed in forest practice application processes.

Rationale: Disallowing forest practices that place power lines at risk will improve reliability, especially in regions in Washington that experience rapid suburban development. Enforcing forest-practice power requirements would reduce activities that place power lines at risk. Requiring those who put power lines at risk to pay to reduce that risk or for damages caused would act as an incentive to reduce forest practices that adversely affect electricity reliability.

Arguments For: Cutting trees to allow very thin stands abreast power lines creates significant reliability risk. Such practices should not be allowed, or those who benefit from such cutting should bear the burden for the risk or damage that results. At the least, a way should be found to ensure that utilities have an opportunity to work with the public before cutting begins. A good first step is to ensure that power related issues remain on the forest practices application so that utilities can benefit from practical access to the information generated by these applications.

Arguments Against: Disallowing current practices that place risk on power lines may significantly reduce the amount of developable land in Washington and concomitant jobs and revenue.

8.5.2 Reliability Enhancing Strategies: Generation and Transmission Sector.

1. Mandate Minimum Levels of Generation Reserves be Maintained.

Description: Establish that power providers or distribution companies must maintain, by plant or contract, some level of reserves.

Rationale: The availability of a reserve margin protects the system against power shortages. Mandating the acquisition of reserves guarantees their availability.

Arguments For: While market forces *may* facilitate construction of sufficient and timely supplies, they do not guarantee it. Mandating reserves guarantees sufficiency at a specific level above market supply.

Arguments Against: Mandating a specific level of reserves can lead to the construction of unused, uneconomic plant. Instead, the notion of long-term supply sufficiency should be separated from short-term contingency-caused supply problems. Market mechanisms should be fostered to deal with contingencies. (see following strategy)

2. Facilitate Development of Market Mechanisms to Address Short Term Supply Shortages.

Description: Require power providers or distribution utilities to develop specific service and contract alternatives for addressing supply shortage contingencies and authorize them as necessary. These could include a broader application of voluntary curtailment and interruption contracts for customers. Large-volume customers could be granted access to the market and required to make their own supply sufficiency arrangements.

Rationale: Sufficiency can be attained through decreased demand as well as increased supply. Knowing that a certain level of supply shortage is covered through flexibility in customer demand provides the same security as generation held in reserve.

Arguments For: The concepts of appropriate reliability and unbundled services (plus innovative new services) provide a basis for developing new mechanisms for addressing supply shortages. Customers have very different reliability needs and some may be willing to voluntarily reduce their consumption if the alternative is to pay high hourly market prices during periods of peak demand. Some European countries have used such energy management programs for years, using radio controls to curtail even residential consumption during peak demand periods.

Arguments Against: These approaches will develop naturally. There is no need to require utilities to develop them. However, until such mechanisms are in place there may be a period of increased risk from supply shortages. Some of these alternatives, such as installing the controls to curtail loads when necessary, may be costly to implement.

3. Establish an Independent System Operator, TRANSCO, or other Independent Transmission Management Organization.

Description: Work with regional and western transmission-owning utilities to form an independent transmission management organization. Such organizations can take many forms depending on profit or non-profit status and scope of operation. The Federal Energy Regulatory Commission is promoting the formation of Independent System Operators (ISOs). ISOs have already been formed in California, New England, the Pennsylvania-New Jersey-Maryland region (PJM), and the Midwest. These new entities exercise direct operational control over regional, high-voltage transmission systems, and either operate or coordinate operations of lower-voltage, subtransmission systems. While the primary purpose for forming independent transmission management organizations, such as ISOs, is to facilitate competitive wholesale generation markets, they may also have reliability benefits. This strategy is also described in Sections 3.0 and 4.0.

Rationale: An independent transmission management organization could be an effective response to potential reliability problems on the bulk power system. Utilities that own both transmission and generation have an incentive to operate the transmission system in ways that benefit their own generation, potentially undermining system reliability. By operating the transmission system over a wider area, an ISO may have access to better information about developing reliability problems in real time. Finally, a transmission management organization would exercise control over all parties that might affect transmission reliability, including utility and non-utility generators.

Arguments For: The current system of fragmented transmission ownership is not sustainable in a more competitive industry. Utilities currently have some financial incentive to operate the system unreliably, since doing so may benefit associated businesses, while the consequences are just as likely to be borne by competitors as by the utility that caused the problem. States are unable to exercise effective authority over transmission owners because of the interstate nature of the transmission grid, and attempts to create enhanced federal authority may not go anywhere. Even if the industry succeeds in getting mandatory reliability standards passed by Congress, enforcement is likely to be spotty, at best. And the rapidly increasing number and complexity of transactions scheduled across the transmission grid greatly increases the likelihood of errors and breakdowns in communications between neighboring control areas. The current system is simply not designed to ensure reliability in a competitive electric market.

Arguments Against: There is no evidence that the transmission system has experienced decreasing reliability as a result of changes in power markets. The current system of voluntary compliance with WSCC standards will be sufficient to carry the region through until the formation of NAERO. Mandatory compliance with standards set by NAERO, or a western equivalent, is a better way to ensure grid reliability while not disturbing the current system of utility control areas. The dominance of BPA and the publicly-owned utilities in the Northwest greatly complicates the formation of a transmission management organization, especially a privately-owned one operated for profit. An ISO that covers a wide region may actually *decrease* reliability because it will not be sufficiently attuned to reliability issues that are specific to local areas. Attempts to implement congestion management schemes that change the way transmission is currently scheduled in the WSCC may be risky. There is simply no need to create a regional super-bureaucracy to deal with a problem that doesn't exist.

4 Promote Increased Deployment of Distributed Generation

Description: Utilities and the state should increase their support for deployment of distributed generation systems such as fuel cells, microturbines, windmills, or solar systems. A further description of these technologies is included in Section 2.0 and of programs that might be considered to encourage their implementation in Section 9.0.

Rationale: Strategically placed utility-scale systems could help improve power quality on the distribution system and reduce system losses. Larger systems, such as cogeneration, can help provide reliable power to areas that are transmission-constrained. Residential-scale distributed systems such as solar panels or fuel cells can provide enhanced reliability to on-grid customers located in areas where interruptions are a chronic problem. They are in many cases the most cost-effective way to serve off-grid customers.

Arguments For: Large commercial and industrial buildings are an increasingly attractive target market for vendors of fuel cells and microturbines. Residential-scale systems can also be cost-effective in some circumstances, particularly off-grid or in areas where reliability is a problem. To the extent that customers bear the majority of the cost of these systems, their deployment increases the likelihood that customers will pay for and get the level of reliability they desire.

Arguments Against: Integrating distributed systems may pose technical challenges. Utilities should not use ratepayer money and the state should not use taxpayer money to provide financial support to projects that provide a benefit only to individual parties. Increased deployment of distributed systems might lead to stranding of distribution or transmission costs.

Endnotes Section 8.0

1. ESSHB 2831 was enacted in 1998 and is not related to SB 6560, which directed this study.

2. IEEE proposed standard P1366 Guidelines, developed by the Task Force on Distribution Reliability Indices.

3. One of Washington's utilities, which generally does not track interruptions statistically, counted all its interruptions, including those caused by lightning that may have lasted only a second or two. The utility calculated a SAIFI of 8.30 interruptions (per customer per year). This contrasted to an average SAIFI of 1.19 for utilities reporting only sustained interruptions. It is impossible to say whether the utilities with the better SAIFI actually have better reliability, because they do not count momentary interruptions.

4. In the following example, a hypothetical event is described along with the calculation of a correct SAIFI and SAIDI ratio — assuming that all necessary data are collected. Following the description is an examination of the potential data inconsistencies that can result from different data collection approaches and limitations.

Imagine a tree falls on a feeder line with 20,000 customers. An automatic recloser (breaker) takes the whole line out for 5 seconds, then recloses, re-energizing the line. The fault is still there when it recloses and so it reopens again for 10 seconds. When it recloses the second time fuses have blown and the fault section is cut off from the head of the feeder. Therefore half the customers are safely restored after 2 interruptions lasting 15 seconds. Thirty minutes later a utility crew is able to switch some of the remaining customers (25% of the feeder) temporarily to another circuit, restoring them to power. Fixing the line break takes 3 hours at which point some customers are immediately restored while others are restored block by block as blown fuses are replaced.

The actual customer interruptions and duration would be calculated thus:

10,000 x 15 seconds +

5,000 x (15 seconds + 30 minutes)+

4,975 x (15 seconds + 30 minutes + 3 hours)+

5 x (15 seconds + 30 minutes + 3 hours + 5 minutes)+

5 x (15 seconds + 30 minutes + 3 hours + 10 minutes)+

5 x (15 seconds + 30 minutes + 3 hours + 15 minutes)+

5 x (15 seconds + 30 minutes + 3 hours + 20 minutes)+

5 x (15 seconds + 30 minutes + 3 hours + 25 minutes).

This leads to a total of 2 interruptions for 20,000 customers or 40,000 customer interruptions and a total of 1,212,420 minutes of interruption. Interruption indices would be calculated thus:

SAIFI = 40,000 / 20,000 = 2 (interruptions per customer)

SAIDI = 1,212,420 / 20,000 = 60.62 (average minutes of interruption for each customer)

In actuality, utilities would not calculate this number.

First, most utilities would not count interruptions lasting less than one or five minutes. This would result in a reduction of SAIFI by 50 percent, from 2 to 1, and slightly reduce SAIDI by the 10,000 customers who were out for only 15 seconds. This is consistent with the proposed industry standard.

Second, most utilities would not know where the power was out. They would wait until they received a phone call from a customer to start the time of duration and send a crew to find the fault and see how many customers were affected. This would result in undercounting duration because some time would likely elapse between the start of the interruption and the first phone call.

Third, some utilities track the impact of switching and other aspects of incremental restoration while others do not. This would result in a duration difference between utilities because some would report the number of customers restored by switching and others would continue to count them as without power. In fact, some utilities would count all the customers without power until the last customer was restored. This would lead to an over-counting of duration, which would offset the undercounting that occurred above, but to what degree? Some utilities claim this averages their counts within five percent of the actual.

Fourth, utilities use different methods to estimate the number of customers affected. Some utilities do not know how many customers are on individual feeders; numbers change frequently due to new development and the reconfiguration of circuits. Other utilities attempt to keep accurate customer counts updated monthly to the level of laterals (shorter lines connected to a large feeder). In other cases the number of affected customers is estimated by crews on the scene.

5. Average refers to an arithmetic mean, where the total number of interruptions (or minutes of interruption) is divided by the total number of customers. Calculations were made using the best available data provided only by utilities that were subject to the study.

6. Data from two utilities was dropped from the statewide analysis because they reported momentaries as well as sustained interruptions (those lasting more than five minutes). They reported SAIFIs as high as 8.3 (interruptions per customer). Their SAIDIs (minutes of interruption) were comparable to other utilities, reflecting that fact that many very short interruptions do not add up to many minutes of duration. Occasional outlier and questionable data were also dropped from the analysis.

7. The United Kingdom requires utilities to report customer level reliability. However, not all UK utilities have that capability. France requires utilities to provide prospective customers with a five-year reliability profile (power delivery and power quality). That capability is not yet in place for all French utilities.

8. Data are from a period that included some severe winter weather (Jan./Feb. 1997) and more mild winter weather (Nov./Dec. 1997). This may indicate that these percentages are typical.

9. The highest expenditure per mile of distribution line was reported by Seattle City Light, the next highest expenditure was $5,991. Seattle City Light has a high customer density of 199 customers per mile of distribution line and a major urban network that is different from any other in the state.

10. Some utilities monitor key locations on a regular basis, such as substations. Temporary monitoring at customer locations occurs when a problem has been discovered or a complaint has been made.

11. 6560 Study - Topic Area Meeting - Reliability, July 8, 1998.

12. In 1998, 8 of 14 recorded complaints were really the same complaint. Counting these only once, the total for 1998 would be seven – slightly higher than some years and less than for others, though 1998 is not yet over.

13. WAC 194-22: Washington State Curtailment Plan for Electric Energy, Most utilities offer “interruptible” contracts to large industries. Utility requested or state mandated curtailment does not refer to such contracts and would only occur after these interruptible contracts have already been invoked.

14. Bonneville Power Administration, *1997 Pacific Northwest Loads and Resources Study*, December, 1997.

15. 6560 Study – Area Topic Meeting – Reliability: July 8, 1998.

16. This simple analysis only looks at 1997 versus the beginning year of the data, which varies by utility. It does not look at intervening years. A utility could have an anomalous beginning or ending year that would affect the results. That does not appear to be the case. While data differs substantially across the individual years for some utilities, the data trend is firm. No utility appeared to have an noticeably anomalous beginning or ending year.

17. In the future, non-utility entities may desire to construct and operate infrastructure that normally has been the responsibility of utilities. The NEC exempts construction from its standards based on whether or not it will eventually be owned and operated by a utility (as indicated by a utility license). Non-utility operators may be discouraged from constructing and offering these services if they are subject to the NEC.

18. A typical tariff reads, “...the customer shall provide adequate protection for equipment, data, operations, work and property under his control from (a) high and

low voltage, (b) surges, harmonics, and transients in voltage, and (c) overcurrent..." Puget Sound Energy, Schedule 80, General Rules and Provisions, #10.

19. WAC 480-100-186 regulates frequency. WAC 480-100-191 regulates voltage.

20. When a customer reports a problem, a utility may set up equipment at a specific location to see if the problem is reoccurring. If it was a one-time event, it will not be recorded. Some utilities locate monitoring equipment at key locations. This kind of monitoring may increase if technological capabilities continue to bring the cost of such equipment down and if utilities begin to find such information more valuable.

21. WAC 480-100-186.

22. "Compliance," means that equipment is *not* vulnerable to problems that can arise when microprocessor dates change from 1999 to 2000.

23. There is no clear distinction between which facilities are transmission and which are distribution. High-voltage facilities (230 kV and above) whose main purpose is transmitting bulk power over long distances are clearly transmission. Low voltage facilities (12.5 kV and below) whose main purpose is transmitting power to individual homes and businesses are clearly distribution. The facilities that fall in-between are known as sub-transmission and can be classified as either transmission or distribution, depending on their primary function.

24. For example, power purchases by U.S. IOUs increased from 563 TWh in 1990 to 843 TWh in 1996, while sales for resale increased from 444 TWh to 608 TWh over the same period. Energy Information Administration*, The Changing Structure of the Electric Power Industry: Selected Issues, 1998*, July, 1998, Table 9.

25. In November of 1998, Montana Power and Puget Sound Energy announced that they reached agreement to sell these facilities to Pennsylvania Power and Light.

26. The Washington Energy Facility Site Evaluation Council (EFSEC) has approved permits for three commercial combustion turbine facility sites at Satsop, Chehalis and Creston, Washington. The three units represent a maximum of approximately 1,648 megawatts capacity. Additional sites have been approved in Oregon.

27. See CEC news release at http://www.energy.ca.gov/releases/98_releases/98-07-23_powerprojects.html

28. California Energy Commission, Wholesale Energy Price Review, September 1998, http://www.energy.ca.gov/electricity/wepr/9809WEPR.HTM

29. For example, investor-owned utilities must "…endeavor to avoid interruptions of service, and, when such interruptions occur, …reestablish service with a minimum of delay." WAC 480-100-076

30. Dr. Brian Wharmby. United Kingdom Office of Electricity Regulation. Speech at conference Reliability in a Deregulated Market. Arlington, Virginia, September, 1998.